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Oxycombustion process in pulverized coal-fired boilers: a promising technology for CO_2 capture

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ABSTRACT

This paper describes a promising oxygen-based process (oxycombustion process) enabling CO_2 capture from coal-fired power plants. The technology involves the replacement of the combustion air by pure oxygen diluted in recirculated flue gases, and will be applicable with limited required adaptations to existing designs of pulverized coal-fired boilers. Oxycombustion performance using PRB coal with flue gas recirculation (O_2/CO_2 environment) has been successfully demonstrated and characterized on a 1.5 MWth plant and compared to those previously measured in operations using air as the oxidant. Optimization of the boiler parameters was performed to obtain maximum benefits from the oxygen/flue gas configuration. An important parameter impacting the combustion performance was the flue gas recirculation flow rate. The overall combustion characteristics were comparable to the air firing case. The NO_x emissions from oxycombustion tests were significantly lower by nearly 70% than the air-fired case, and the CO_2 content in flue gas was increased from 15% in air-fired case to eventually 80% in O_2-fired modes. The flue gas volume exiting the boiler has been shown to reduce by nearly 70%, thereby improving the economics of efficient capture, reuse, and sequestration of carbon dioxide. Economic studies indicate that the cost of electricity produced via oxycombustion of coal is potentially 20% lower than conventional technology when CO_2-capture is taken into consideration.

INTRODUCTION

Over the past years, environmental concerns regarding various combustion-generated pollutants have grown dramatically. In addition to acid rain precursors (NO_x and SO_x), which were the first to be targeted and which remain a short-term challenge, carbon dioxide emissions have became a major concern due to the "greenhouse effect". As a consequence, the governments have tightened the regulations on SO_2, NO_x and mercury emission limits in a growing number of areas, and have started to regulate CO_2 release into the atmosphere and/or encourage the development of new technologies aimed at controlling CO_2 emissions.

The power generation industry and specifically coal-fired units account for a large amount of the pollutants mentioned above with around 10% of the worldwide CO_2 emissions resulting from coal-fired power plants. It is imperative, therefore, that new combustion concepts be developed and customized for power plant needs, so that existing and new coal-fired units may utilize these options and comply with existing and future emission regulations.

The traditional pollutant-control-method involves a post-combustion flue gas treatment system comprising as many treatment devices as regulated pollutants. A conventional post-treatment line, currently, would include a wet- or dry- flue gas desulfurization (FGD) for SO_x removal, an electrostatic precipitator (ESP) for particulate removal and a selective or non-selective catalytic reduction (- SCR or SNCR) system for NO_x reduction (where regulated). Future regulations on mercury and CO_2 emissions may necessitate the modification of existing equipment and/or the provision of additional equipment to deal with these emissions. Such a pollutant control methodology comes with several drawbacks:

1) Most of these installations are "flue-gas flow-rate" dependent. They are, therefore, very expensive when applied to conventional air-combustion systems, where the inert gas nitrogen would play a "ballast" role during the process.

2) In general these post-treatment devices control one specific pollutant, thus requiring the addition of a new device (added financial burden) each time a new pollutant is restricted. It is easy to imagine how a nitrogen-free process would benefit from a highly reduced flue gas flow rate. This is achieved by replacing the combustion air with pure oxygen in the combustion process. The resulting five-fold reduced flue gas volume leads to smaller flue gas treatment costs. Added to this, the removal of nitrogen from the process leads to the flue gas being highly enriched with carbon dioxide allowing its relatively straightforward capture for eventual sequestration without the need for expensive and energy-consuming-separation systems.

The oxy-combustion technology development initiative offers a variety of alternatives. To develop a retrofit technology applicable to existing boilers a portion of the flue-gas is recycled thus replacing the nitrogen with CO_2 and keeping the boiler characteristics and dimensions the same as the air-fired base-case. For new plants, the volume of flue gas recirculation (FGR) would be set to a minimum value enabling a more compact boiler design and resulting in significant reductions in boiler costs. Figure 1a shows an air-fired system including the present/future emission control devices, while Figure 1b shows the reduced-size devices or absence of these devices when "oxycombustion technology with flue gas recirculation" (Oxy-FGR) is implemented. This paper describes a demonstration of this technology at pilot scale, and investigates the economic feasibility of this concept.

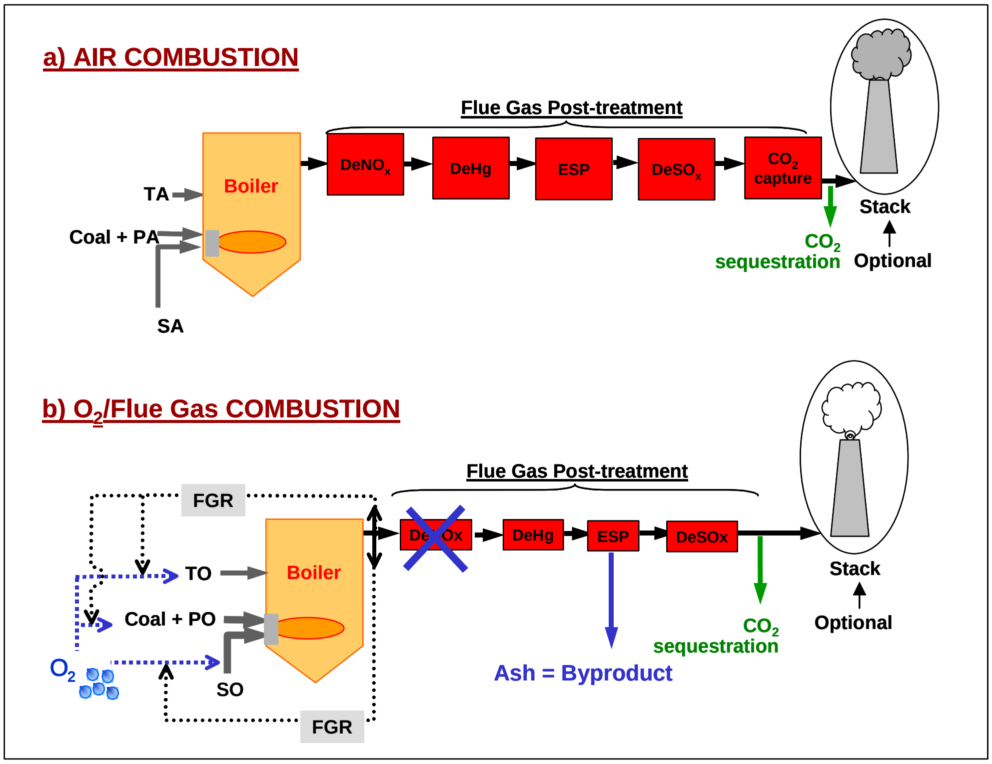

Figure 1: Boiler Schematic with Flue Gas Post-treatment. a) Existing Air-fired Operation b) Oxygen-fired Operation using Flue-gas Recirculation

OBJECTIVES

In partnership with the U.S. Department of Energy's National Energy Technology Laboratory, Air Liquide is developing and optimizing the oxycombustion of coal process as an efficient and cost-effective approach for new plants and for potential repowering applications to improve the environmental performances of existing coal-fired fleet. The main objectives of this study are to: (1) demonstrate the feasibility of the oxycombustion technology with flue gas recirculation on Babcock & Wilcox's 1.5MWth coal-fired pilot boiler, (2) measure its performances in terms of emissions and boiler efficiency while selecting the right oxygen injection and flue gas recycle strategies, and (3) perform an economical feasibility study, comparing combustion modification via oxygen enhancement approach with alternate technologies.

EXPERIMENTAL DEMONSTRATION

Description of the Test Facility

The demonstration part of this project was performed in collaboration with Babcock & Wilcox (B&W), on B&W's 1.5MWth (5MMBtu/hr) Small-Boiler Simulator (SBS) (Figure 2).

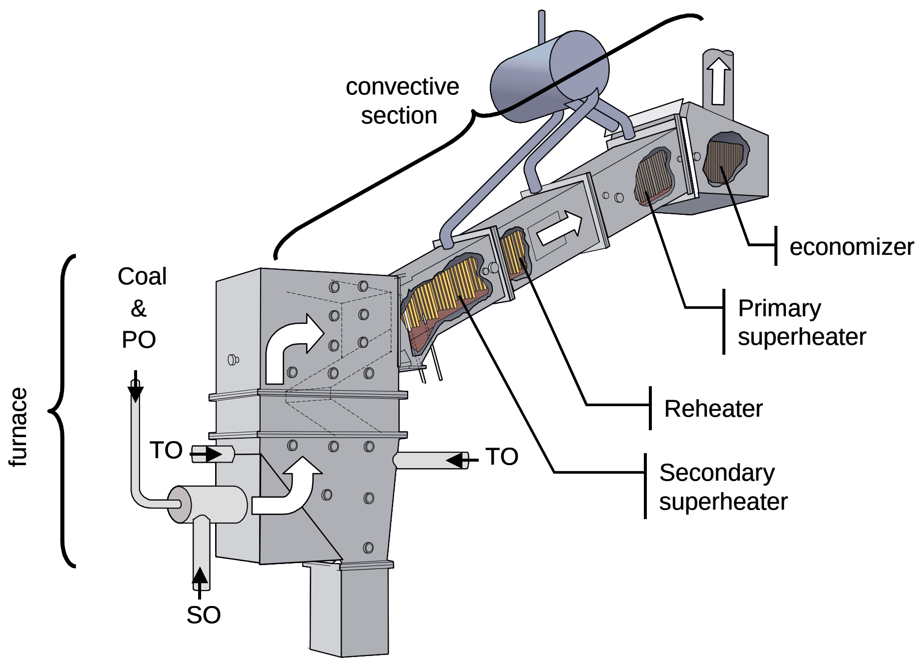

Figure 2: B&W Small Boiler Simulator (SBS)

This facility accurately replicates the combustion and convection heat transfer characteristics of a full-sized boiler. The convective pass section consists of four different sections simulating secondary superheater, reheater, primary superheater, and economizer.

The unit has a complete gas analysis system consisting of gas analyzers for O_2, NO_x, CO, CO_2, and SO_2 measurements. The flue gas is drawn from the stack by a vacuum pump, filtered, transported in a heated sample line to the refrigeration unit, and passed to the appropriate analyzers. The stack fly ash can be isokinetically sampled and analyzed for carbon content to determine carbon utilization in the system.

A video camera is available for recording flame pictures and a Flameview™ imaging system is available for temperature mapping of the flame.

For the duration of the tests, liquid oxygen was delivered to the test facility and stored in a tank. The liquid oxygen is vaporized in an ambient vaporizer, sized for winter operating conditions (-7ºC/20ºF air temperature). The oxygen is regulated to an appropriate pressure and delivered to the test area via a copper line. The oxygen delivery control system is integrated with the boiler-simulator, allowing oxygen flows to be controlled and monitored from a central location. It is also integrated into the boiler safety interlock system.

Tests have been performed with a low-sulfur sub-bituminous coal. Its composition was: moisture 26.85 %, ash 6.29%, volatile 47.2%, carbon 72.21%, hydrogen 5%, nitrogen 0.92% and sulfur 0.41% (on a dry basis). The heating value of the coal was 12,505 Btu/lb (on a dry basis).

Test Results

Overall combustion characteristics in oxycombustion process with flue gas recirculation (O_2/CO_2 environment) have been measured and compared to those previously measured in air-firing operation. Optimization of the boiler parameters was performed to obtain maximum benefits from the oxygen/flue gas configuration. The main parameters impacting the combustion characteristics that was investigated was the flue gas recirculation flow rate.

Overall Combustion Characteristics in O_2/CO_2 Environment

The feasibility of switching from air to O_2-enriched flue gas (O_2/FGR) operation has been demonstrated, and an operating procedure for smooth transition from air to O_2/FGR then back to air conditions has been developed.

A stable flame has been obtained under O2/FGR conditions, attached at the throat, and flame shape was similar to air firing. From a visual judgment, the oxy-fired flame was colder than the air-fired flame, presumably because of higher specific heat of CO_2.

Furnace exit gas temperature (FEGT) measurements were performed for base line air firing and oxy-firing while the overall mass flow rate was kept constant. The average FEGT, under oxy-firing conditions, was slightly lower than for the air firing case. This could be a positive impact for a boiler operating with higher than normal FEGT. The convection pass exit gas temperature (CPEGT) was measured for both oxy-firing and air cases. It was generally higher in oxy-conditions. Further studies are required to address boiler heat transfer and steam generation characteristics.

NOx emission characteristics

The NO_x emissions were considerably lower in O_2-fired conditions than in air-baseline, the reduction rate averaging 70%. The baseline NO_x emission range was 0.22 to 0.26lb/MBtu (with a low-NOx burner) and dropped to 0.07 to 0.08lb/MBtu under oxycombustion conditions. NOx emissions are also impacted by oxygen flow rate into the primary air zone and by overall flue gas recirculation rate. This can be explained by higher flame temperature resulting from increased O_2 content in the primary air zone of the boiler or from lower flue gas flow rate. Such higher temperature in the reducing zone of the boiler promotes the conversion of recirculated NOx and devolatilized fuel nitrogen to molecular nitrogen.

Impact of Flue Gas Recirculation Rate

As a reference, before optimization, mass flow rate of the coal and oxidizers in the combustion zone, when air was switched to flue gas and oxygen, has been maintained. The flow rate of recirculated flue gas was then optimized for retrofit applications in order to minimize adverse effects on heat transfer and steam generation, when switching from air to oxy-flue-gas operation. During the tests, the total flue gas recirculated was varied from 80% to 95% of total flue gas, and furnace exit gas temperature (FEGT) and convection pass exit gas temperature were measured to provide insight on the amount of flue-gas recirculation required. Figure 3 shows the effect of recirculated gas flow rate on NO_x emissions. The NO_x emissions decreased to a minimum of 0.065 lb/MBtu. Under these conditions of recirculated flue gas flow rate, the overall mass flow rates through the boiler of air firing and oxygen firing conditions were similar.

Figure 3 shows that NO_x emissions decrease as the recirculated flue gas flow rate decreases. This is explained by the presence of a higher flame temperature with lower flue gas flows which increases the destruction of NO_x in the reducing zone of the burner.

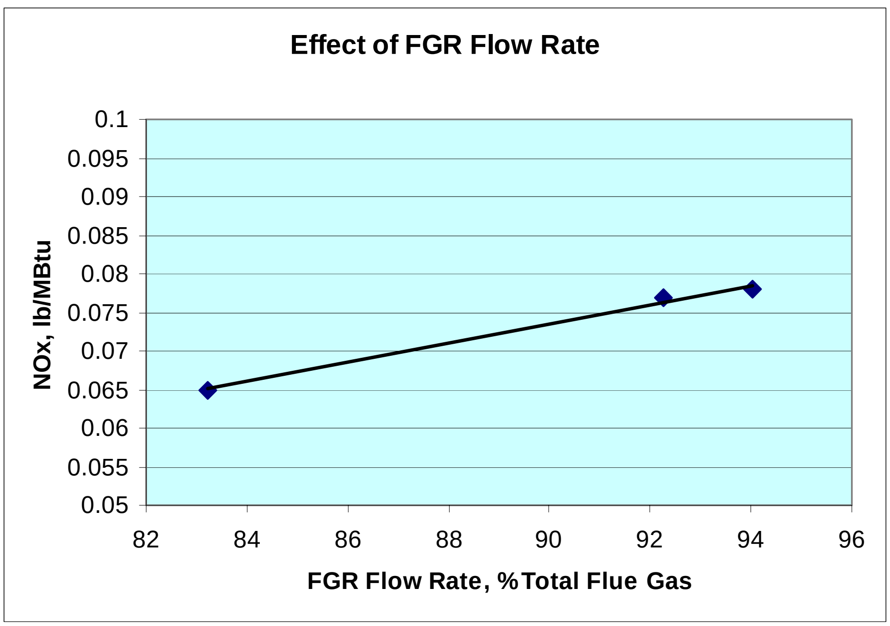

Figure 3: Effect of Recirculated Gas Flowrate

CO_2 content in flue gases

One area of concern during the current series of tests was the amount of air infiltration into the flue gas line. During the tests the maximum CO_2 concentration that could be obtained was 80% (corrected to 3% boiler exit oxygen concentration). The infiltrated air was approximately 5% of the total boiler gas flow rate (i.e., air, oxygen, flue gas and coal). The SBS boiler is balanced draft and operates under slightly negative pressure. During the tests the furnace pressure was increased to slightly positive to minimize air leaks into the boiler. The main sources of air leaks are suspected to be the I.D. fan, baghouse and scrubber that were operating under higher negative pressures.

This level of air leakage is a good representation of potential air leaks in commercial boiler retrofits from the ESP, air heater, etc. However, for retrofit units, there are other alternative boiler operating procedures that could be employed to reduce air leaks.

ECONOMIC ASSESSMENT

The economic assessment of this project was performed in collaboration with Illinois States Geological Survey (ISGS). Four different types of plants were considered in this study, conventional air-fired PC boiler without CO_2 removal, conventional air-fired PC boiler with CO_2 removal, oxycombustion with wet flue gas recycling (wet Oxy-FGR) and oxycombustion with dry flue-gas recycling (dry Oxy-FGR). In the dry Oxy-FGR, moisture in the recycled flue gas is removed using a conventional condenser. The same plant capacity of 533 MWe (gross output, i.e., sum of turbine power produced) for each plant was considered in this study to make a suitable comparison of all the cases.

Methodology

The following six sections of a plant were considered for the cost assessment: 1) the basic systems of a plant including the boiler and turbine systems and the ESP, 2) SO_2 removal section, 3) NOx removal section, 4) Mercury removal section, 5) CO_2 removal section, and 6) Air Separation Unit (ASU) and related specific components of gas recycle in an oxy-FGR process. PRB coal is considered as the fuel in this study

The lime spray dryer (LSD) process for SO_2 removal was chosen for burning low sulfur PRB coal. A removal efficiency of 90% was assumed based on the general performance of this process. A hot side, high dust configuration was selected for the selective catalytic reduction (SCR) process with a NOx removal efficiency of 90%. A mercury removal efficiency of 80% was assumed for the activated carbon injection (ACI) process. The Fluor Daniel Economine Mono ethanol-amine (MEA) process was employed for capturing 90% of CO_2 in flue gas. It should be noted that the cost of CO_2 compression is not included in the calculations. The various steps are described here in more detail.

<u>Process simulation</u>

The process simulation studies provide mass and energy balances of the main stream of the plant. For the conventional PC plant, four main process areas are simulated: ❶ boiler system, ❷ steam turbine generator, ❸ flue gas cleaning, and ❹ CO_2 separation process. The Oxy-FGR process involves the former process areas ❶ ❷ & ❸ and the air separation unit (ASU).

<u>Auxiliary power modeling</u>

Certain process items of the power plant consume significant amounts of electricity. These auxiliary power requirements reduce the net power output of the plant, and thus affect the generation cost.

The **net power generation** is defined as the **gross power generation** minus the auxiliary power use, and the **net plant efficiency** is defined as the net power generation divided by the total thermal input. The following auxiliary power requirements are then used for estimating the **electricity generation cost**.

Auxiliary power consumptions is mainly related to the process variables such as air, flue gas, and water flow rates. The relationship of the auxiliary power loads can be functions of the process variables of the system. Based on available data from literature, correlation formulas have been developed. The main auxiliary power load items of each of the five process areas identified above are as follow: combustion and generation process areas (coal handling, pulverizers, fans, blowers, pumps, steam turbine auxiliaries…), flue gas cleaning process area (ESP, FGD, sorbent handling, pumps, SCR, Hg removal…), CO2 separation (MEA) process and the air separation unit.

Cost model: Capital and Operating and Maintenance (O&M) cost modeling

The cost model is described here in more detail.

Capital cost.

Classification of process areas is shown in Table 1. Estimation of capital costs is based on reference plants developed by the USDOE (1). Only the gas turbine generator is not relevant to this study (steam turbine plants).

The remaining 13 areas, related to the conventional PC plant, are listed in Table 1. Some process areas specific to this study have also been considered, due to additional flue gas treatment devices (NO_x, SO_x, Hg removal), CO_2 separation and oxygen needs for to the Oxy-FGR process. Those additional process areas are listed in bold in the table.

1. Coal handling	7. Steam turbine generator
2. Coal preparation & feed	8. Cooling water system
3. Feed water &misc.	9. Ash/Spent sorbent handling system
4. PC boiler & accessories	10. Accessory electric plant
5. Flue gas cleaning ESP **Dry FGD** **SCR** **Mercury removal**	11. Instrumentation &control 12. Improvements to site 13. Buildings and structures **14. CO2 separation** **15. ASU (O2 production)**
6. HRSG, ducting and Stack	**16. Flue gas recirculation**

Table 1: Classification of process areas

Each process area listed above is composed of its sub-areas, and sub-sub areas (individual equipment). The direct capital cost can be determined at each level. For example consider a steam turbine generator which would be a process area for a power plant. The process area of the steam turbine generator has five sub-areas, (steam TG and accessories, turbine plant auxiliaries, condensor auxiliaries, steam piping and TG foundations) and for the 1st sub-area, i.e., steam TG and accessories, there are seven equipment: turbine generator, bearing lube oil coolers, bearing lube oil conditioners, control system, generator coolers, Hydrogen seal oil system and generator exciter.

The cost estimation at the **process area level** is considered in this study. However, for CO_2 separation, flue gas cleaning, flue gas recirculation and ASU process areas, more detailed breakdown costs are estimated.

O&M cost

Cost and expenses associated with operating and maintaining of a plant include operating labor, administrative and support labor, maintenance labor and materials, consumables and fuel cost.

Operating and supportive labor can be estimated on the basis of the number of operating jobs (OJ) required to run the plant.

Annual cost of maintenance labor and materials is estimated as a percentage of the installed capital cost. The percentage varies widely, depending on the specific processing conditions and the type of design for each process area. The representative percentage is selected for each process area from available data.

Consumable materials include water, chemicals (ammonia, lime, SCR catalyst, activated carbon, amine…), and other consumables:

Results from the process simulation studies provide the mass flows of the consumables listed above. Their costs are estimated according to their unit market prices.

Results

Process Calculations

Basic process parameters are obtained from simulation studies of the oxy-FGR and conventional PC plants. The overall process performances for the conventional and Oxy-FGR power plants are presented in Table 2.

The results show that the amounts of coal used in different plants are comparable. Only a small reduction in coal use was observed for the wet oxy-FGR due to the reduced heat loss by the flue gas. The conventional air blown PC without CO_2 removal had the highest net generation efficiency. The addition of the MEA process for CO_2 removal dramatically reduced the net efficiency of the PC plant. Both the wet and dry oxy-FGR processes exhibited higher generation efficiencies than the conventional plant with CO_2 removal. The wet oxy-FGR process had slightly higher generation efficiency than the dry process.

The impact of reduced flue gas volume on the ducting and stack was considered for the oxy-FGR process. In the case of the air blown PC equipped with CO_2 removal, a scenario in which a portion of the steam in the MEA process was withdrawn was considered. The impact on the sizing of downstream steam turbine loop, such as the cooling water tower, and the associated costs were estimated.

Results show that the total capital costs for the oxy-FGR processes are about 8% higher than a conventional PC plant without CO_2 capture, but about 9% less than a conventional PC plant with CO_2 removal. The oxy-FGR process has much lower capital costs than the conventional PC plant for the flue gas cleaning and the ducting/stack system, mainly due to the reduced volume of flue gas.

	Conventional PC Plant		Oxy-FGR Process	
	Without CO_2 Removal	With CO_2 Removal	Wet Oxy-FGR	Dry Oxy-FGR
Coal Flow Rate (lb/hr)	524,982	524,982	504,064	524,472
Steam Turbine Power (MWe)	533	435	533	533
ASU Power (MWe)	0	0	73.5	76.5
Other Aux. Power (MWe)	31.9	47.2	23.9	24.6
Net Power (MWe)	501.3	387.6	435.9	432.2
Net efficiency, HHV (%)	37.0%	28.6%	33.5%	32.0%

Table 2: Overall Process Performances of oxy-FGR and Conventional PC Plants

Levelized cost of electricity

The levelized costs of electricity generation are listed in Table 3. The levelization factor for the total capital requirement (TCR) was 16.9% assuming the inflation rate of 4.1%, discount rate of 9.25% and 30-year life of plant. Levelization factor of 1.54 was adopted for all O&M costs except for coal, and 1 for coal.

	Conventional PC Plant		Oxy-FGR Process	
	Without CO_2 Removal	With CO_2 Removal	Wet Oxy-FGR	Dry Oxy-FGR
Total capital requirement (TCR)	**$/kWe**	**$/kWe**	**$/kWe**	**$/kWe**
	1,223	1,850	1,515	1,547
O& M costs (1st year)	**mills/kWh**	**mills/kWh**	**mills/kWh**	**mills/kWh**
Fixed O & M	9.15	15.38	12.72	12.83
Variable O&M	3.28	7.92	2.77	3.14
Fuel	10.48	13.56	11.68	12.24
Levelized costs	**mills/kWh**	**mills/kWh**	**mills/kWh**	**mills/kWh**
Fixed O & M	14.11	23.70	19.60	19.76
Variable O & M	5.06	12.20	4.27	4.84
Fuel	10.48	13.56	11.68	12.24
Levelized capital costs	33.70	50.99	41.75	42.63
Levelized cost of power	**63.35**	**100.45**	**77.30**	**79.48**
Levelized cost of power (1st year)	**56.62**	**87.85**	**68.92**	**70.84**

Table 3: Costs of Electricity for Conventional PC plants and Oxy-FGR Processes

The levelized cost of electricity for the conventional air-blown PC with CO_2 removal is higher than the dry Oxy-FGR process by 27% and wet flue-gas recycle Oxy-FGR process by 30 %. The cost for conventional air blown process without CO_2 removal is about 18% lower than the Oxy-FGR process with wet gas recycle. The cost estimation presented here indicates the economic attractiveness of the Oxy-FGR technology for the new PRC coal-fired power plant.

Costs for retrofit

As discussed in the earlier section of the report, the cost analysis for retrofit applications considers only those existing components in a plant that need to be modified, and other necessary new components in the retrofit. These include the modifications of LSD flue gas desulphurization process and ACI process due to the change of flue gas flow rate, elimination of SCR process in the Oxy-FGR plant due to reduced NOx emissions in oxygen combustion condition, new installment of MEA process in the conventional PC plant, and new installment of ASU and gas recycle system in the Oxy-FGR plant.

The comparison results of the components mentioned above are listed in Table 4.

	Conventional PC plant		**Oxy-FGR Process**	
	Without CO_2 Removal	With CO_2 Removal	Wet Oxy-FGR	Dry Oxy-FGR
Net output, MWe	501	388	436	432
Total Plant Cost	**$/kWe**	**$/kWe**	**$/kWe**	**$/kWe**
ASU			261	283
MEA		247		
ACI	4	5	2	2
SCR	60	78		
LSD	100	129	70	68
Total	**164**	**459**	**333**	**352**
O&M cost	**mills/kWh**	**mills/kWh**	**mills/kWh**	**mills/kWh**
1. FOM				
ASU			3.10	3.17
MEA		3.54		
ACI	0.34	0.44	0.24	0.23
SCR	0.07	0.08		
LSD	0.80	1.03	0.49	0.46
Subtotal	1.20	5.10	3.82	3.85
2. VOM				
ASU&OEC				0.35
MEA		3.67		
ACI	0.72	0.93	0.24	0.21
SCR	0.34	0.44		
LSD	0.43	0.56	0.48	0.50
Subtotal	1.49	5.60	0.72	1.06
Total O&M cost	**2.69**	**10.70**	**4.55**	**4.91**

Table 4: Comparison for Retrofit of Power Plant

Retrofitting a conventional PC plant with CO_2, SO_2, NOx and Hg removal equipment installations increases the total capital cost by $295/kWe while the Oxy-FGR modification increases the capital cost by $169/kWe for wet Oxy-FGR and $188/kWe for a dry Oxy-FGR process. The total O&M cost of an Oxy-FGR retrofit is about half that of the MEA retrofit. These comparisons thus indicate the economic competitiveness of Oxy-FGR technology in the retrofit cases.

CONCLUSION

In conclusion, the oxycombustion technology with flue gas recycling (FGR) has been successfully demonstrated and characterized on a 1.5 MWth plant. The overall combustion characteristics were comparable to the air firing case. The NO_x emissions from oxycombustion were significantly lower (70%) than the air-fired case. The air infiltration in the boiler under O_2-conditions has been reduced to a final level of approximately 5% of the overall stoichiometry, increasing the initial CO_2 content in flue gas from 15% in air-fired conditions to eventually 80% in O_2-fired conditions. Alternative boiler operating procedures are expected to reduce even more the air infiltration to achieve higher CO_2 concentration in flue gas for further sequestration or reuse. The flue gas volume exiting the boiler has been reduced by 70%, thus making easier any additional flue gas treatment which may be necessary before stack exhaust or CO_2 reuse or sequestration.

The economic feasibility of the oxycombustion process and conventional air fired process was studied in detail. The oxycombustion technology has costs of electricity that are about 20% lower than conventional technology when CO_2-capture is taken into consideration.

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